XII. OLD OIL FIELD WATERFLOOD OPERATIONS AND ENHANCED OIL RECOVERY POTENTIAL

A. INTRODUCTION

Substantial emphasis has been placed on secondary and enhanced oil recovery techniques in recent years. Research in enhanced oil recovery advanced because of higher exploration costs, increased demand for petroleum products, and decreased replacement of domestic reserves.

Usually, only 5 to 30 percent of a reservoir's original-oil-in-place (OOIP) can be recovered by primary production. As much as 30 percent more of the OOIP may be recovered by supplementing primary energy with secondary recovery techniques. In selected reservoirs, an additional 30 percent of the OOIP may be recovered by application of tertiary or enhanced oil recovery processes.

Primary production accounted for approximately 7 percent recovery of the OOIP in New York State's old oil fields. Secondary recovery by waterflooding has resulted in an average recovery of an additional 14 percent of the OOIP. Waterflooding in the old oil fields has continued to the present. Twenty-eight percent of 1986 oil production in New York is attributed to this technique.

During initial field development, the operator strives to recover as much oil and gas as possible during the primary stage of production by efficiently utilizing the reservoir's natural energy to drive oil through the rock pores and into the producing wells. This natural energy results from: 1) the downward expansion of gas overlying the oil (gas cap drive); 2) the expansion of gas in the oil (solution gas drive); 3) water intrusion into the oil-bearing zone from an aquifer (water drive) and; 4) the force of gravity (gravity drive). In many reservoirs, all four drive mechanisms may be present, but only one or two recovery mechanisms will dominate. During the

life of a reservoir, shifts in recovery mechanisms may occur. For example, a volumetric reservoir under solution gas drive may shift to a gravitational drive after the natural pressure is depleted.

The purpose of this chapter is to examine the various methods of enhanced oil recovery and their impacts in New York State.

B. DEFINITIONS

The literature concerning oil recovery methods employed after primary production has different definitions for secondary and tertiary recovery operations. Some authors restrict "Enhanced Oil Recovery" to the tertiary mode while others consider it to include both secondary and tertiary recovery. Others view secondary operations involving water or gas injection in conjunction with any additives, chemicals or other gases, as tertiary techniques. For the purpose of this text, the terms secondary and tertiary will apply to the order in which an operation is conducted rather than any actual characteristics, and the term enhanced recovery will include all recovery methods other than those dependent on a reservoir's internal energy.

Specific rock and reservoir properties must be defined prior to discussing enhanced recovery methods. Ideally, these properties are determined from data gathered during the drilling and primary production phases. However, it should be noted that most oil wells in New York predate the use of sophisticated petroleum engineering data gathering and analysis techniques.

During or immediately after the drilling of a well, core samples may be obtained and well logging operations are conducted to analyze the pay zone. These initial tests provide the engineer with enough information to determine whether the well should be completed or plugged and abandoned. Specific information which is later used to evaluate the application of enhanced recovery methods is also gathered at this time. The following physical data are essential for such an evaluation:

1. Permeability - is the ability of the rock to allow fluid movement through its interconnected pores. For reservoir analysis, the following terms are derived from permeability:

    a. effective permeability - is determined for a given fluid at a saturation less than 100 percent and is the fluid conductivity of the porous media at a given saturation where other fluids are present.

    b. absolute permeability - is the permeability of a rock that transports a single fluid at 100 percent saturation. This term is most useful when determining rates of production or injection.

    c. relative permeability - is the ratio of the effective permeability to the absolute permeability.

2. Porosity - is that fraction of the rock volume occupied by pore space.

3. Saturation - is the percentage of pore volume occupied by a specific fluid such as gas, oil or water.

4. Wettability - is the tendency of one fluid to spread on or adhere to the rock surface.

5. Fluid viscosity - is the ability of a fluid to resist flow. The less viscous a fluid, the greater its mobility. (Typical viscosity of the light oil produced in New York ranges from 2 to 6 centipoise with corresponding gravities of 37° to 43° API.)

6. Original-oil-in-place - is the portion of the total pore volume occupied by oil at initial conditions and is determined volumetrically from analysis of cores and logs.

7. Recovery factor - is the percentage of original oil in place which can be recovered by the application of a specific recovery mechanism.

Although other significant parameters are involved, the above information

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is the basic data necessary for an evaluation of the potential for enhanced recovery.

During the primary production phase, other reservoir characteristics are evaluated which include the following:

1. Homogeneity of reservoir - is the degree of consistency in a reservoir. The homogeneity can be approximated by analyzing well interference tests, production and pressure histories, core data and logs, and other petrographic and stratigraphic information.

2. Dip - is the average angle of inclination from horizontal of the strata in a reservoir.

3. Diffusivity - is the determination of the rate at which a fluid will readjust in response to a pressure disturbance in the reservoir.

Although these factors are important, dip and diffusivity are not commonly considered in New York due to the relative maturity and horizontal nature of the State's oil reservoirs.

The best method for determining the feasibility of a full scale enhanced recovery operation is the pilot project. Especially useful in undeveloped areas, a pilot project is a mini-operation designed to assess the performance of the enhanced recovery technique before large quantities of capital are committed to a full scale project. The location of the wells is chosen to best represent the majority of the reservoir. The operating condition of the pilot wells must be closely monitored for an accurate evaluation of the project.

The information derived from a pilot is used to better evaluate the following:

1. Incremental oil recovery

2. Optimum pattern configuration

3. Saturation distributions

4. Areal sweep efficiency – the ratio of the volume swept at any time to the total volume subject to intrusion.

5. Mobility – the ratio of the permeability to viscosity with a single fluid in reservoir. When one fluid is displaced by another, the mobility ratio is defined as mobility of the <u>displacing</u> fluid to that of the <u>displaced fluid</u>.

C. WATERFLOODING

1. General

When the economic limit of a field under the primary stage of production is reached, a determination must be made as to the future production potential of the field. The application of one or more enhanced recovery techniques may be warranted based on reservoir characteristics and past production performance. Although waterflooding is the most commonly applied secondary recovery method, other enhanced recovery techniques utilizing miscible fluids, chemicals, or heat may be applied based on the characteristics of the reservoir rock and fluids. A production potential of 1,000 – 2,000 barrels per acre-foot is a generally accepted minimum yield for initiation of a waterflood. Oil price, water availability, construction costs, drilling and/or workover costs, etc., will also affect the ultimate feasibility of the project.

The amount of oil displaceable by water can be determined from relative permeability data and core testing. Typical sandstones can be flooded to a residual oil saturation of 10 – 40 percent. Carbonate reservoirs, which may have extremely complicated pore geometries, can have much lower displacement efficiencies. In sandstones, the residual oil saturation to waterflooding is also governed by the interfacial tension at the oil/water phase boundary.

Absolute permeability and homogeneity in the pay zone and the mobility

ratio of the oil and water are critical to sweep efficiency. However, injection well locations and completion methods are also important.

After deciding to initiate a waterflood operation, the operator will choose a well pattern. The majority of waterflood operations in the U.S. utilize the "five-spot" waterflood configuration. Figure 12.1 indicates this and other flooding patterns.

The five-spot pattern offers quick response and good sweep efficiency, and it conforms well to existing spacing patterns. Variations may be advantageous to specific recovery operations. Generally, peripheral and line drive injections offer better recovery efficiencies in formations with extreme structural relief. Also, peripheral or line drives may use less water than pattern floods.

Once the optimal pattern has been determined, the operator must consider injection well completions, the quality, quantity and availability of water, water treatment, injection equipment, storage facilities, operating pressures, and the mechanical condition and maintenance of the injection and production wells.

Injection wells can be drilled or converted from existing production wells. Converted wells should undergo a thorough testing program to ensure integrity.

Water disposition is a crucial consideration in any waterflood project. After securing its availability, the operator must design the treatment and water handling facilities.

Water retrieved from freshwater sources can contain large amounts of oxygen, suspended solids and bacteria which require treating. Injection water should be protected from the atmosphere and injected immediately after filtration. Anaerobic sulphate-based bacteria that must be eliminated are often found in produced waters. Knowledge of the injection and formation

FIGURE 12.1 ENHANCED RECOVERY FLOOD PATTERNS
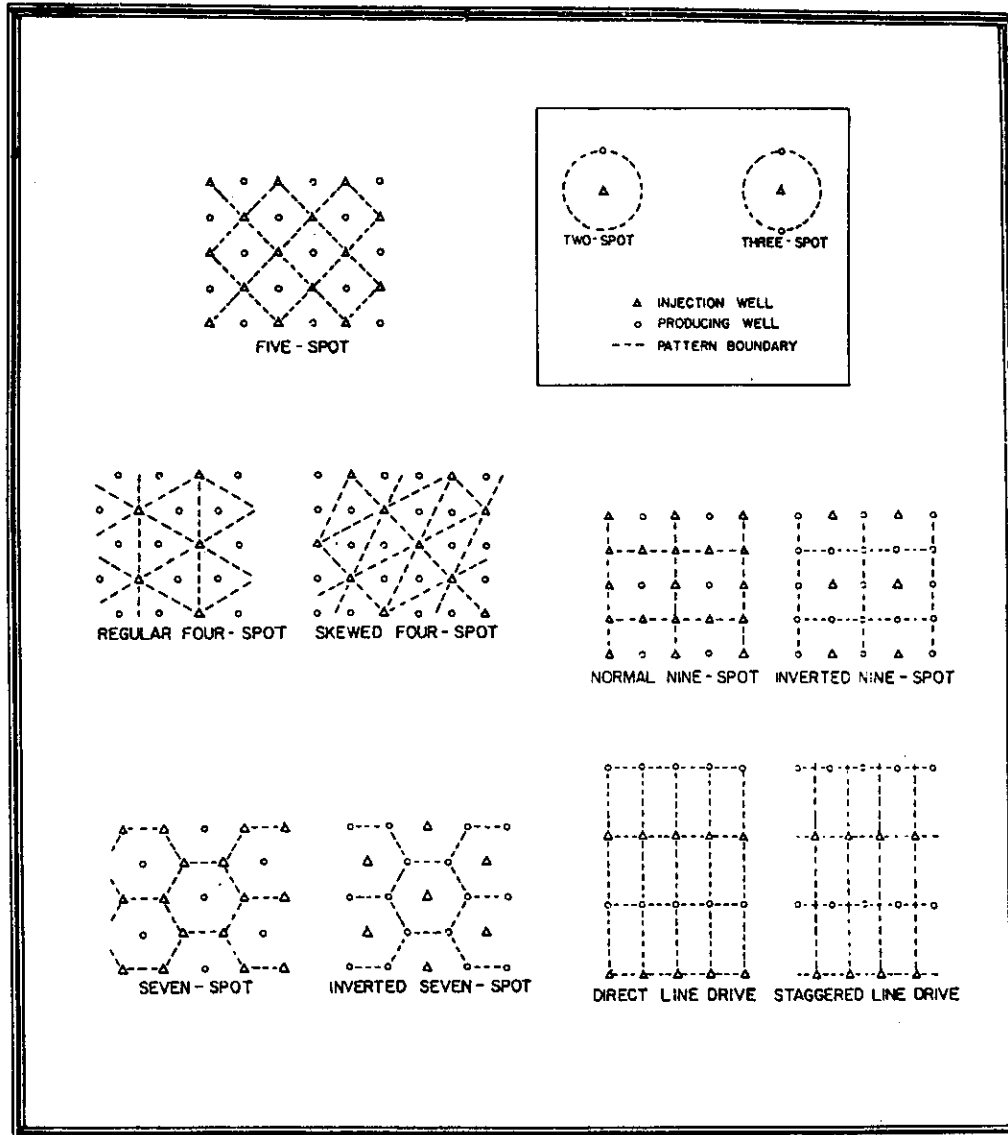
FIGURE 12.1

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water is essential to avoid such precipitates as iron oxide, iron sulfide, calcium carbonate, calcium sulphate, and barium sulphate. Sulphate precipitates are insoluble and are the most damaging but these precipitates can be prevented through the use of polyphosphates, phospate esters and phosphanates.

Operators must also treat the injected fluids to avoid reservoir plugging, shale swelling, and corrosion of surface and down-hole equipment.

There are two types of injection systems; open and closed. In the open system, water is obtained from surface waters or fresh water wells. In the closed system, produced water is recycled and re-injected. The water may be treated chemically and by aeration and sedimentation processes before injection although some operators attempt to keep all dissolved constituents in solution. Fluids used in the open system require more treatment than the closed system.

Operation of an injection system requires a comprehensive operating and maintenance program. Regular inspections of the wells and the surface production facilities must be conducted. Water quality and corrosion control are particularly important.

Inspections of injection wells should include, but are not limited to: 1. temperature, flowmeter and radioactive tracer surveys when casing, packer and/or tubing leaks are suspected. 2. annular pressure checks, 3. wellhead pressure surveys to monitor injection pressure and formation plugging, and 4. caliper logging to ensure tubing integrity.

Following is a discussion of waterflooding operations in New York State including an overview of the Department's existing regulatory program.

2. Waterflooding In New York

Water injection was legalized in New York in 1919, after the primary

energy in most of the existing fields was depleted and prior to the
formulation of engineering concepts and studies relative to water injection.
This does not mean that current waterflood operations do not adhere to sound
engineering principles; in fact, these fields prompted the early detailed
engineering studies on waterflooding.

The oil bearing sands currently being waterflooded in Allegany, Steuben
and Cattaraugus counties meet the criteria for good waterflood candidates. A
typical core in an Allegany County field might show a reservoir with good
upper and lower permeability barriers and no water encroachment. The pay zone
is approximately 16 to 22 feet thick with 11 to 15 percent porosity. Oil
gravity is 41° to 44° API, and oil saturation is approximately 65 to 75
percent. Studies have shown that fields with these characteristics are good
waterflooding prospects. There are many oil sands in New York which do not
have adequate porosity and permeability for a successful waterflood.

The oil fields in western New York reached peak primary production in 1882
and all time low production in 1912. A sharp decline in primary production and
low primary recovery are typical of solution gas drive reservoirs when natural
gas is produced in an uncontrolled manner with the oil thereby dissipating the
natural reservoir energy. This had occurred by 1912 when each well averaged
only 1/8 to 1/10 barrel of oil per day and it was estimated only 7 percent of
the original oil in place had been recovered (NYS Geological Association, 1957).
Figure 12.2 shows those oil fields which are being waterflooded.

Waterflooding was discovered accidentally prior to 1907 when the leaking
of freshwater through faulty casing into the oil sand of a pressure depleted
reservoir resulted in a production increase in offset wells. When the cause
of the production increase was recognized, a practice of purposely making
"leaks" in the casings of other wells began (NYS Geological Association,
1957). The first documentation of the perforation of casing for water

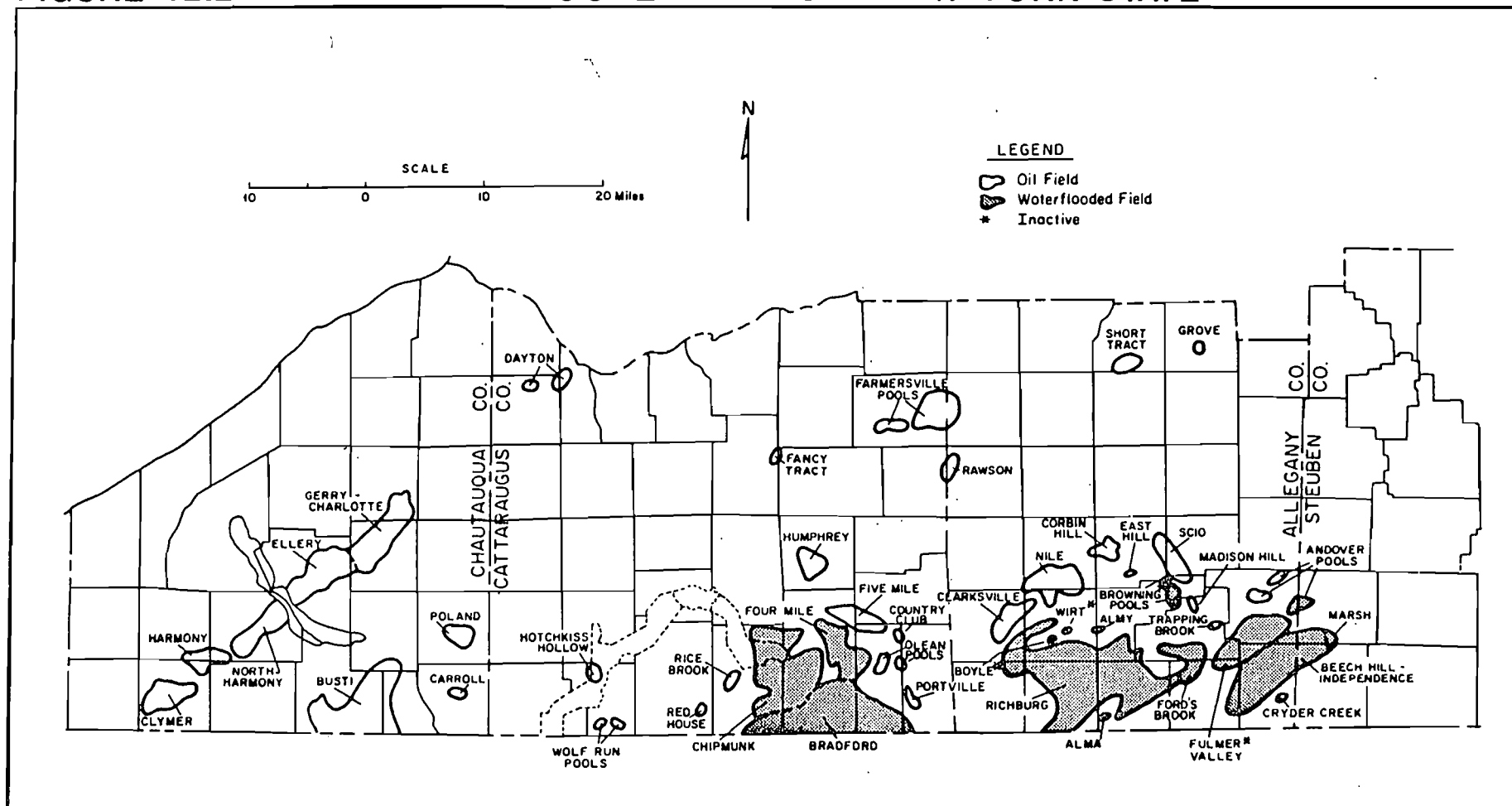FIGURE 12.2

WATERFLOODED FIELDS IN NEW YORK STATE

FIGURE 12.2

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injection dates back to 1911. A random conversion of oil wells into water input wells followed. Water injection proved successful in increasing production where pressure maintenance by gas injection had failed in New York.

There are approximately 25 active waterflood operations in New York. These are concentrated in Allegany, Cattaraugus and Steuben counties. Approximately 316,000 barrels of oil were produced in 1985 from secondary recovery operations in New York State. The number of waterflooded production wells is estimated to be 2,050; the number of injection wells reported was 1,745. The five-spot is the most common pattern found in New York's waterflooded oil fields. It is estimated that the correct number of producers and injectors in waterflooded fields is 20 percent higher than the number reported. To date, incremental waterflood production has been estimated at 14 percent of original oil in place (Van Tyne, and Foster, 1980). An estimated 8,059,000 barrels of oil could be recovered from the currently developed enhanced recovery operations in New York's old oil fields.

a. Historical Waterflood Operations - Prior to development of the Medina Formation, practically all drilling operations in New York State were conducted in the oil fields of Cattaraugus, Allegany and Steuben counties. Considerable advancements in methodology have occurred since the inception of drilling for hydrocarbons in New York. A historical perspective is offered due to its impact on present day technologies, environmental problems and the State's regulatory program.

Input and production wells were basically drilled in the same manner, from the 1920's through the 1950's. The accepted practice was to drive a 10 inch hole through the unconsolidated surface deposits and set 8 inch pipe. A 7 5/8 inch hole was then drilled through the freshwater horizons down to 300 or 500 feet. Six and five-eights or seven inch casing was set but not often cemented to surface. A 6 1/4 to 6 inch hole was then drilled through the

producing formation to a total depth of approximately 600 to 2,000 feet.
Drill cuttings of the pay zone were saved and compared to electric logs (if
any) to determine the "shoot" zone (NYS Geological Association, 1957).

An early form of fracturing or stimulating a well, "the shot" was
intended to break-up or fracture the producing formation to increase the rate
of production or injection. Wells were shot with liquid nitro-glycerin which
was lowered into the hole in thin metal containers to a point opposite the
producing formation. An average shot would use 3 quarts of nitroglycerin per
foot of producing formation and was detonated by a "squib" or "go-devil"
containing two fused sticks of dynamite (NYS Geological Association, 1957).
Before detonation, the well was filled with water to prevent the blast from
expending itself up the hole.

Stimulation methods have improved in effectiveness and safety over the
years so that nitroglycerin is rarely used for fracturing in the oil and gas
fields today. However, nitroglycerin may be a more effective stimulation
technique in certain shallow reservoirs with very close spacing. The
transition from nitroglycerin to other stimulation techniques evolved from the
negative impacts related to nitroglycerin stimulation such as increased
potential for wellbore and formation damage.

While some long-time oil producers still endorse nitroglycerin
stimulation, such techniques have drastically declined over the past 10 - 15
years. Evidence of this decline is best demonstrated by the fact that only
one company now services New York's oil producing area and by the completion
reports submitted to the Department from operator's engaged in step-out,
infill, and perimeter drilling in waterflood areas.

Completion of a water injection well usually consisted of running 2 inch
tubing on a packer to just above the producing formation where it was cemented

with approximately 20 sacks of cement (NYS Geological Association, 1957). The tubing was then connected to a water injection plant and each well or injector station was equipped with a meter to monitor the amount of injected water.

Production wells were basically completed in the same manner except that the tubing was not usually run on a packer or cemented. If the producer was to be pumped, a pump barrel was run on the tubing and a pump plunger inserted with sucker rods. The rods were activitated by either a single well jack or by jacks connected to a central power unit (NYS Geological Association, 1957).

Water for the flooding came mainly from both shallow and deep freshwater wells. Some produced brine was also recycled for injection.

Air lift jet pumps were used on the water wells in the early days of waterflooding but these were soon replaced by turbines, submersible pumps and sucker rod pumping jacks. The air lift pumps injected large amounts of dissolved oxygen into the water while the other pumps do not inject oxygen into the system, thereby reducing pitting and corrosion.

Filtered and treated water was stored in water tanks before gravitating to triplex positive displacement pumps. The pumps provided the pressure necessary for injection, usually 0.5 to 1.3 pounds per square inch per foot of depth or 800 - 1,300 psig surface pressure. The average rate of injection was 1/2 barrel of water per day per foot of sand (NYS Geological Association, 1957).

Annular gas was flared-off or utilized to run engines and furnish heat on the lease. The oil and water were piped through 2 inch lines to a gravity separator where the oil was siphoned into wooden stock tanks for sale. The water was sent to settling ponds before being discharged into surface streams. Gas from the separator was returned to the lease gas line system or flared. Standard stock tanks were 10 feet high by 10 feet in diameter and held 140 barrels (NYS Geological Association, 1957).

At the start of a waterflood, mostly oil and gas are produced. Oil production peaks when the oil bank which is pushed ahead of the injected water reaches the producing well (see Figure 12.3). Water breakthrough occurs soon after and increases until it is no longer profitable to produce the well. The well is then plugged and abandoned. Many of the wells in the old fields were not plugged properly by modern standards. It was common for the operator to recover salvageable equipment and leave wells unplugged due to changes in the 1919 plugging and abandonment statutes which allowed a well to remain unplugged if it had potential use as a water injector.

Some of the historical drilling and completion methods described in this section are still common practices in the oil fields today. DEC is aware of the problems associated with these practices and their potential impact on the environment. Considerable effort by the Department is being concentrated in this area to formulate environmentally sound and economically feasible strategy.
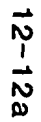
b. Current Waterflood Operations - Current practices for drilling waterflood production and injection wells closely resemble those used to drill wells in past years in the old oil fields except that surface casing is now required to be cemented at least 75 feet below the lowest fresh water zone.

Waterflood well drilling activity peaked in the years immediately following the legalization of waterflooding in 1919. This increased activity continued through World War II but then began to decline and fluctuate through the mid 1960's in response to market conditions. During the oil crisis of the 1970's, increases in waterflood drilling activity were observed with peaks occurring in 1974, 1977 and 1978.

Drilling - Presently, most of the drilling activity in waterflood areas is peripheral expansion of existing operations. Waterflood operators direct much of their activities to production, plugging and abandonments, step-out drilling of production wells and conversions of production wells to injectors.

FIGURE 12.3

WATERFLOODING

Central Injection Plant

Fresh Water or Brine Tank

to other Injector well

to other Injector well

Injection Well

to separator

Injection Well

Water is pumped down injection well

Water & oil go up production well

Impermeable Rock Layer

Water is pumped down injection well

Oil Formation

Water flows through rock, pushing oil ahead of it.

FIGURE 12.3

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Both air rotary and cable tool rigs are used in waterflood drilling operations. The decision is based on operating costs, time constraints, or operator preference. Since the formations in New York's waterflood areas are usually 600 to 2,000 feet deep and are practically depleted, with low pressures, either method can adequately meet drilling needs.

Casing and Cementing - As mentioned previously, wells drilled in the old oil fields were cased and cemented utilizing the available technology at that time. However, many of today's problems are the result of that technology. Conductor pipe was generally driven in for hole stabilization, and surface pipe would then be set below any high rate water zones. This pipe was rarely cemented. If cement was used, minimal amounts would be grouted from the top and/or displaced from the bottom of the hole. Using minimal cement was a common practice for cable tool operations, since cable tool drilling does not create torque on the surface pipe. As rotary rigs became more popular, greater amounts of cement were required to prevent erosion of the formation at the casing seat and disassembly of the casing from the torque of the rotary action. Still, the casing was rarely cemented to the surface.

The Federal UIC Program, enacted in the Safe Water Drinking Act of 1974, required that operators cement the surface pipe of all injection wells from the casing seat to the surface. Many operators responded by cementing the surface strings of their injection and production wells (realizing that the producing well may be converted to an injector in the future). As DMN met initial staffing requirements in 1982, the cement requirements for gas well development, of 450 feet of casing or 100 feet into bedrock, whichever is greater, were applied to the old oil fields with slight modifications of casing depth. Less surface casing was approved on an individual basis.

By 1983, oil field operators were required to cement their water strings

to the surface, unless good cause could be demonstrated to waive the requirement.

Today, operators run anywhere from 300 to 500 feet of 7-inch surface pipe depending on the depth of the deepest freshwater zone. In most areas of the State, bedrock and potable water zones are very near the surface, hence adequate protection is realized. Another problem associated with cementing in the oil fields of southwestern New York is a sporadic "thief" or lost circulation zone. Where present, this zone is highly fractured and permeable, and cement is lost. In some areas the lost circulation zone appears as a small cavern caused by drilling disturbance. The following methods are used to cement "thief zones":

a. Set surface casing above the "thief zone" and isolate the remaining wellbore with cement or a packer so that annular fluids will not be lost.

b. Set surface casing through the "thief zone" and add appropriate lost circulation material to the cement in order to plug off the zone.

c. If the zone is close to the surface, DMN may approve, on an individual basis, the circulation of cement to this zone instead of to the surface. The operator must demonstrate that there is no chance of migration into freshwater zones.

Procedures a and c require DMN approval as does any alternate plan of action.

The most commonly used method in industry today for cementing the surface casing is the pump and circulate technique. However, approximately 70 percent of the surface casing cement jobs in New York's waterflood fields utilized other methods such as the displacement or grouting technique.

The displacement method requires the appropriate amount of cement to be placed in the hole prior to setting the surface pipe. After the cement is placed in the hole, surface casing is run into the hole with a plug on the

end. As the casing moves through the cement, cement is displaced around the pipe. Water is continually added to the casing to prevent it from floating.

Grouting is accomplished by pumping cement from the surface through smaller diameter tubing placed down the annular space. However, blockage or bridging can occur up hole which would require remedial cement operations.

Pumping and circulating as specified in Chapter 9 is the most common and effective method for cementing operations. Here surface casing is installed, and the cement is pumped down the pipe followed by a plug and water which displaces cement up around the surface pipe. The plug and water prevent backflow and floating of the casing.

The production and injection string is usually 1 1/2 to 2 3/8 inch tubing which is run from the surface to total depth. This tubing is either set on a packer, and/or cemented above the producing zone in the injection wells.

Stimulation - As mentioned previously, hydraulic fracturing (hydro-fracturing) is more commonplace than nitroglycerin stimulation. Hydro-fracturing applies energy at a slower and more controlled rate to the formation, minimizing formation damage.

Generally, one or more zones need to be stimulated and a multi-stage stimulation is performed. Sometimes these zones must be notched to accept stimulation fluids. Notching is accomplished by running 1 1/2 inch pipe which contains a special end nozzle. This pipe is suspended in the hole with the nozzle opposite the deepest production zone. Sand and air are then pumped down the hole and ejected out the nozzle which is oriented 90° from the bottom of the pipe so that the air and sand are directed toward the sand face. As the sand is forced out the nozzle, the pipe is rotated to create a 360° notch into the production zone. After the first notch is completed, the pipe is moved to the next higher zone and the process begins again, until all the

notches have been formed.

After notching, the zones are hydraulically fractured, usually, in one of two ways. The less commonly used method employs a "straddle packer". This packer has two rubbers and is run-in on 3 inch tubing so that the rubbers straddle the lowest notch. The packer is then set and pressurized water and sand with small amounts of additivies, surfactant, acid and/or foam are forced through perforations in the pipe between the rubbers and into the formation. Fracture pressures range from 1,500 to 3,500 psi with pressures occasionally exceeding 4,000 psi. After the fracturing is complete, the straddle packer is moved uphole to the next higher notch and the process is repeated.

The more common method involves an injection of fracture fluids down a 3 inch pipe set on a single rubber packer. The hole is filled with pea gravel to just below the upper most notch and the packer is set just above the notch and the zone is then treated by the same fracturing procedures. After the fracture is complete, the pea gravel is cleaned out to the next lower notch and the process is repeated.

Completion - After the well is stimulated, most injection and production wells are completed open-hole with the tubing end just above the waterflooded horizon.

Injection tubing is hung from the surface and set on packers and cement or sometimes by cement alone. Frequently, operators will cement from the bottom of the string to approximately 100 feet above. When leaks occur in the casing or tubing, the operator runs a 1-inch macaroni string with a pack-off element which serves as the injection string and the tubing becomes a form of casing.

Production wells are completed in a similar manner as injection wells except that 2 3/8 inch tubing is hung from the surface by a tubing head and remains suspended in the borehole. If the well is to be pumped, a pump barrel

is run on the tubing and a pump plunger is inserted with sucker rods. The tubing to borehole annulus remains open from total depth to surface where it connects to a gas line. As long as the surface casing is cemented from below the freshwater zones to the surface and the formations above the producing horizon are impermeable, this completion method is environmentally acceptable.

A few operators set the production tubing with cement, but this method can result in gas interference and gas locking of the pump. Other operators do not run surface casing but do run 4 or 6 inch production casing and cement this string to the surface.

Production - The majority of producing wells are pumped by a single well jack (a type of pumping unit) or by jacks connected to a central power unit. Produced fluids are piped through 2 inch lines to a gravity separator where oil is piped into stock tanks for sale. Figure 12.3 indicates a typical arrangement for a waterflood production project.

When produced gas is available in sufficient quantities, it is piped to specific areas on the lease to run engines and to heat tanks or it may be given to landowners for domestic use. Gas is also collected from the tubing borehole annulus and entered into the lease gas line system. When the gas cannot be efficiently utilized by one of these methods, the gas is vented.

Brine Disposal - Produced brines commonly contain chemical constituents indigenous to the produced hydrocarbons and the formation. They usually have high concentrations of chlorides and trace concentrations of heavy metals. Aromatics such as benzene, toluene, xylene and related compounds can also occur at detectable levels in the brine. However, the produced brines associated with the waterflooded fields in New York are very dilute after 70 years of waterflooding with freshwater.

Produced water from the separators is either discharged into surface

waters or stored in tanks or earthen pits prior to disposal into surface

streams or removal for road spreading. Less commonly, the brine is trucked to

a waste treatment plant for disposal. Holding pits or settling ponds are more

widely used than holding tanks. The Department requires earthen pits to be

lined with an impermeable material to contain the brine and prevent

infiltration into groundwater. Effective March 1, 1985, a moratorium was

placed on future unlined separator ponds. Such ponds must be replaced by

storage tanks or lined with an impermeable material as verified by percolation

tests.

A State Pollution Discharge Elimination System permit must be received

from the Department's Division of Water, prior to any discharge or disposal of

waste fluids into surface waters (See Chapter 15 for additional information).

Conversion - When a producing well is converted into an injection well,

the well is said to be "worked-over". A workover rig is usually nothing more

than a scaled down, easily-transportable mast and hoist. Many workover rigs

in New York consist of a large truck with welded mast for pulling tubing.

During workover of the well, the pump, sucker rods and tubing, if necessary,

are pulled and the well is cleaned out to total depth.

Most waterflood projects are initiated in old oil fields where many wells

were drilled prior to promulgation of environmental regulations. It is

required that DEC and the United States Environmental Protection Agency (EPA)

be notified when a production well is converted into an injection well.

Severe environmental problems, particularly contamination of potable water,

have occurred in the past when operators have proceeded with conversion of old

wells without the necessary evaluation of conversion procedures and potential

environmental impacts which are made during the permitting process. DEC staff

review the proposed casing program and determine if any unplugged abandoned

wells are in close proximity to the proposed injection well.

c. <u>Injection Operations</u> - A general "rule of thumb" for waterflooded fields in western New York is that 10 to 15 barrels of injection water are needed to recover one barrel of oil. Sale of pressurized water between facilities is a common practice among New York operators.

<u>Injection Water</u> - Freshwater from drilled water wells or recycled brine from the lease separator can be used for injection water. Water supply wells for the floods are completed in either shallow gravel deposits, 20 to 50 feet deep, or in bedrock, 100 to 300 feet deep. The water from the gravel zone is chemically less stable and more corrosive than the water from the deeper source wells, which contains no dissolved oxygen. The shallow water source wells, however, produce 50 to 150 gallons of water per minute while the deep water source wells produce 30 to 85 gallons per minute (NYS Geological Association, 1957).

Produced water or brine is sometimes recycled and reinjected into the formation although this is not a common practice in New York's oil fields. The local brine requires extensive chemical treatment and filtration prior to injection and contains more impurities than freshwater.

<u>Chemical Treatment and Filtration</u> - Prior to injection, the water is analyzed for dissolved oxygen, free carbon dioxide and pH range. Tests are also conducted to determine the presence and amount of sulfates, iron, manganese, alkalines, chlorides, silica, calcium, magnesium and total solids. The size of the settling tanks and the chemical treatment necessary are determined from these analyses.

Chemicals such as coagulates, caustic materials and chlorine may be added to remove heavy minerals, raise the pH from 6.5 to 8.4 and prevent bacterial growth which can plug the formation and cause the failure of a waterflood. After chemical treatment the water is sometimes filtered through sand, or sand

and gravel filters. If high quality water is required, diatomaceous earth filters are used. Anthracite coal filters were used extensively in the past to remove heavy metals, foreign particles and bacteria, and are still used in some fields today. Sometimes, the water is also chemically treated after filtration with corrosion inhibitors, sequestering agents and additional bactericides.

Injection Pressure and Rate - After chemical treatment and filtration, the water is either stored in tanks prior to injection or injected directly from the filters. Pumps provide the pressure necessary for injection. Injection pressures for the low permeability oil sands in New York are high. If injection pressures exceed the fracture pressure of the formation, which varies from .92 to 2.4 psi per foot of depth or 1,500 - 4,000 psi at the formation face for New York oil sands, the injection fluid could be lost to other formations and possibly break through into overlying freshwater aquifers through propagated or existing fractures.

A step-rate test which is relatively simple, inexpensive and fast, can be used to estimate formation fracture pressure. The results of a typical step rate test for a New York injection well are shown in Figure 12.4. These tests define the maximum injection pressure that can be approached without fracturing the reservoir rock and must be considered as an integral part of any waterflooding operation.

Monitoring of Injection Wells - Monitoring of injection wells to determine the rate and pressure of injected water and to detect leaks and possible migration is important. Rate and pressure recorders or meters are normally installed on each injection pump and flowmeters or pressure recording hook-ups are installed on input wells. However, not every injection well in the waterflooded fields is equipped with a flowmeter or pressure gauge. Current regulations require each operator of a waterflood project keep records

FIGURE 12.4   SAMPLE STEP RATE TEST

FIGURE 12.4
12-20a
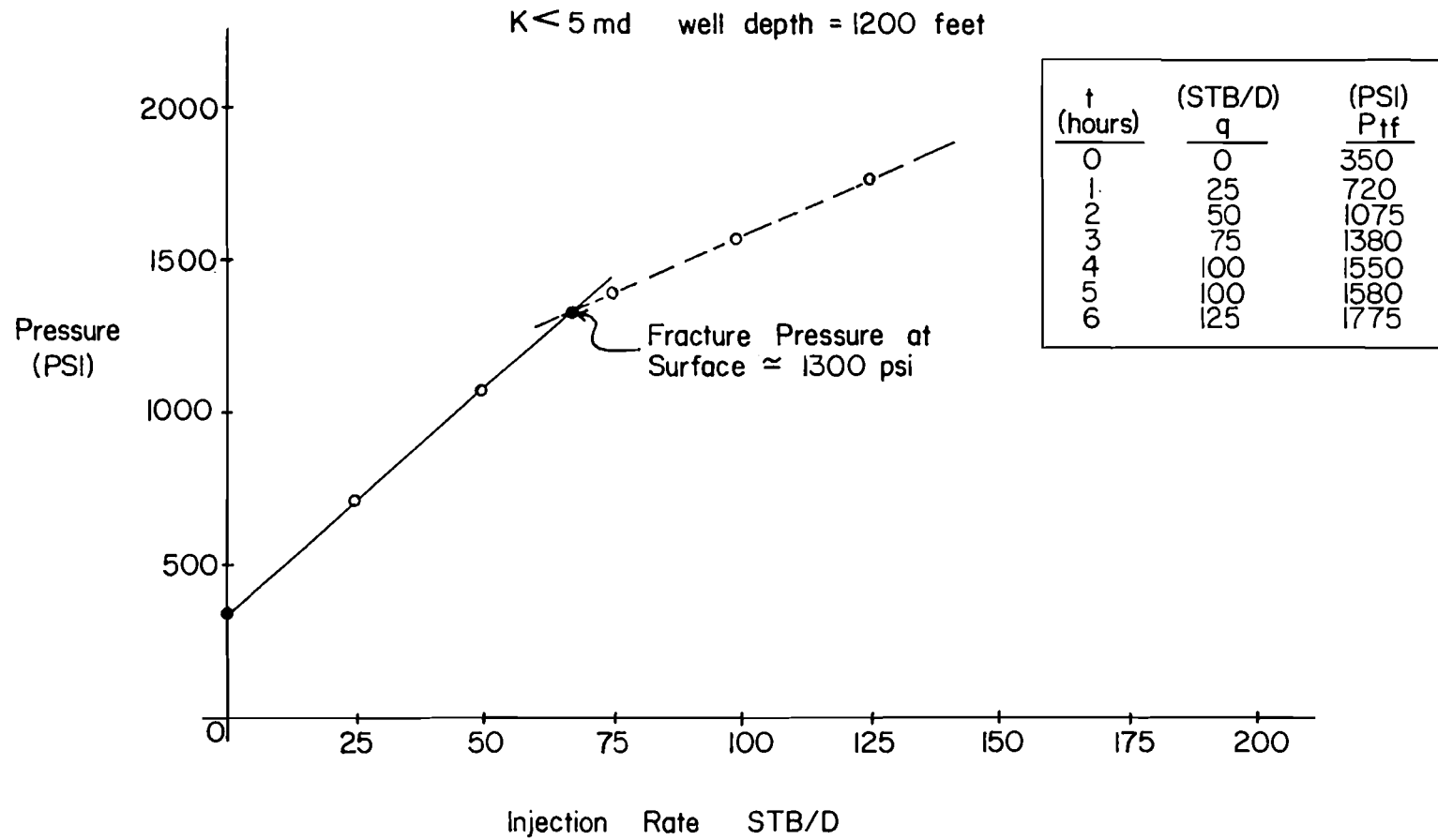
and submit an annual statement showing the volumes of fluid injected and produced and the injection pressures.

3. <u>Plugging and Abandonment</u>

Past plugging practices, although undertaken with good intention, were primitive by today's standards and may ultimately cause significant environmental problems. The earliest abandonment method consisted of pulling casing and depositing debris rock, wooden plugs, or waste metal, etc., in the hole. Later, as waterflooding became more widespread and injection pressures increased, such holes required a better sealant for successful operations. Setting plugs of seasoned timber on top of bridges made of debris was an accepted method of plugging until the late 1960's. By the 1970's, the timber plugs used for abandonments were set at specified depths and topped with cement to seal off producing formations and protect groundwater.

Early records are scarce. DMN is trying to gather information on the location and plugging procedure of abandoned wells in order to prevent further contamination and to pinpoint specific problems. Many thousands of improperly plugged and abandoned wells may exist in western New York. These wells are likely a primary contributing factor to some of the current environmental problems.

Waterflood injection and production wells are plugged in the same manner as other oil and gas wells in New York. Operators must receive a permit from DMN prior to commencing any plugging and abandonment operations. Existing requirements are that 15 foot cement plugs be set: 1. above injected formations, 2. above any producing formation, 3. below the surface casing shoe and, 4. at the surface. In addition, the intervals between the plugs must be filled with mud or another approved fluid to stabilize the hole and prevent

fluid migration.

Some of the following enhanced recovery methods have been used on a
limited basis in New York State. Other methods are untested in New York but
may have future application. A brief description of the application in New
York will be discussed immediately after each section.

D. GAS INJECTION AND IMMISCIBLE DISPLACEMENT

1. General

Gas is sometimes injected into an oil zone or its gas cap to improve
recovery. This gas may consist of flue gas, lease gas, or inert gas. The
injected gas can serve as a displacement fluid or as a mechanism to restore
and maintain pressure in the reservoir.

Gas injected into a gas cap helps maintain reservoir pressure and enhance
gravitational forces which displace oil downward to producing wells (Latil,
1980). This is referred to as a pressure maintenance operation. Gas injected
directly into the oil zone is called dispersed gas injection or immiscible
displacement (Interstate Oil Compact Commission, 1983). In theory, the gas
flows radially from the injectors, displacing oil toward the producers. The
decision to inject gas is often based on the availability of sufficient
supplies of inexpensive gas. Recycled produced gas is sometimes used, but
reservoir pressure will continue to decline and a supplemental supply of gas
must eventually be secured.

Gas requires very little, if any, treating and it can be injected at high
rates into a minimum number of injection wells. It is a poor displacing
fluid, however, because of its low viscosity.

Gas injection for pressure maintenance is most efficient in crestal wells
of reservoirs with a steep anticlinal structure. If the reservoir has enough
vertical relief, such that gravity segregation of the reservoir fluids can
occur, then incremental oil recovery by gas injection can equal that of a

water drive operation.

Historically, dispersed gas injection or immiscible displacement projects rarely recover more than 5 percent of the OOIP. Variations in vertical permeability and the high mobility ratio between oil and gas usually results in gas channeling or over-ride of the oil and thus reducing incremental oil recovery.

New York's oil fields are classic examples of poor candidates for gas injection because they are horizontal structures with no gas cap.

2. New York's Gas Injection Operations

Gas injection was the first method of enhanced recovery tried in New York. The gas was injected while a producer was placed on a vacuum which increased the pressure differential between the injection and production well. Only a slight oil production increase was realized utilizing this method.

The following three sections deal with what many feel are true enhanced or tertiary recovery methods - chemical, thermal, and miscible. These enhanced oil recovery processes offer a great potential for further oil production from selected reservoirs meeting the appropriate screening criteria.

E. CHEMICAL RECOVERY METHODS

Chemically enhanced recovery methods involve the addition of chemicals to injection water which alters fluid properties and/or interfacial tension conditions such that more oil is produced. Chemical methods involve the use of polymers, surfactants and alkaline solutions.

1. Polymer Flooding

The principal types of polymers used are polyacrylamides, polysaccharides and ethylene polyoxide (xanthan biopolymers) (Latil, 1980). Polyacrylamides and biopolymers are used more commonly. Dilute polymer solutions remain highly viscous and are used to increase the viscosity of the displacing fluids.

This in turn lowers the mobility ratio between the oil and injected solution, thus improving sweep efficiency and increasing incremental oil recovery (Interstate Oil Compact Commission, 1983).

Table 12.1 lists the screening criteria for EOR candidates utilizing existing technology. Theoretically, polymer flooding can be applied to a wide range of reservoir conditions. The limit on formation brine salinity is imposed because polyacrylamide solutions degrade when exposed to salts. Biopolymers are less sensitive to salts but require meticulous filtering and protection from bacteria.

2. Surfactant Flooding

Surfactant flooding involves the injection of multiple slugs containing chemicals which lower the oil/water interfacial tension. The mobilized oil is then carried out of the reservoir as an emulsion. In 1932, experiments with soap solution injections were conducted in sands located in Pennsylvania which also extend into New York. These original tests initiated the research on surfactant flooding.

A surfactant flood begins with injection of a saline water pre-flush which conditions and displaces the formation water to protect the surfactant solution. Surfactant injection is followed by a polymer slug for mobility control during displacement.

Generally, surfactants are petroleum sulphonates derived from crude oil which have high interfacial activity and are readily available (Latil, 1980).

The criteria used for screening potential surfactant flood candidates are detailed in Table 12.1. The more successful surfactant floods have been conducted in low-salinity, low-temperature, sandstone reservoirs having moderate-to-high permeabilities.

TABLE 12.1 SCREENING CRITERIA FOR EOR CANDIDATES

TABLE 12.1
12-24a

	Oil Properties			Reservoir Characteristics					
	Gravity °API	Viscosity (cp)	Composition	Oil Saturation	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods									
Hydrocarbon	>35	<10	High % of $C_2 - C_7$	>30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	>2000 (LPG) to >5000 (H.P. Gas)	N.C.
Nitrogen & Flue Gas	>24 >35 for N_2	<10	High % of $C_1 - C_7$	>30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	>4500	N.C.
Carbon Dioxide	>26	<15	High % of $C_5 - C_{12}$	>30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	>2000	N.C.
Chemical Flooding									
Surfactant/ Polymer	>25	<30	Light intermediates desired	>30% PV	Sandstone preferred	>10	>20	<8000	<175
Polymer	>25	<150	N.C.	>10% PV Mobile oil	Sandstone preferred; Carbonate possible	N.C.	>10 (normally)	<9000	<200
Alkaline	13-35	<200	Some Organic Acids	Above Waterflood Residual	Sandstone preferred	N.C.	>20	<9000	<200
Thermal									
Combustion	<40 (10-25 normally)	<1000	Some Asphaltic Components	>40-50% PV	Sand or Sandstone with high porosity	>10	>100*	>500	>150 preferred
Steamflooding	<25	>20	N.C.	>40-50% PV	Sand or Sandstone with high porosity	>20	>200*	300-5000	N.C.

N C Not Critical
*Transmissibility >20 md ft/cp
**Transmissibility >100 md ft/cp

Source: "Technical and Economic Criteria for Selecting Methods and Materials for Enhanced Oil Recovery (or Why CO_2 Fills the Bill in the Permian Basin of New Mexico and Texas)", Interstate Oil Compact Commission Committee Bulletin, vol. 26, no. 2, December 1984.

3. Alkaline Flooding

Alkaline or caustic flooding is similar to surfactant flooding except that the oil/water interfacial tension is reduced by the neutralization of the acids in the crude oil. Chemicals commonly used for this process are sodium carbonate, sodium silicate, and sodium hydroxide (National Petroleum Council, 1984). Although caustic flooding appears simple and inexpensive to apply, the mechanics involved are complicated.

The reservoir conditions suitable for alkaline flooding are shown in Table 12.1

Alkaline flooding and displacement processes are not completely understood but successful application of this process is restricted to formations with higher permeabilities than those found in New York. Present studies are directed toward understanding the mechanics of the system and improving the process by adding polymers and/or co-surfactants.

4. New York's Chemical Drive Projects

Chemical processes have not been attempted on a large scale in New York. In 1972-73, a micellar-polymer project was conducted in Allegany County. The chemical solutions used were provided by Marathon Oil Company which patented the name Maraflood when using these fluids for enhanced recovery. Although no additional oil was recovered, this test did provide valuable injectivity information.

In 1971, a micellar-polymer injection test of the Chipmunk Formation was performed in Cattaraugus County. The micellar slug was injected successfully but injection of the polymer into the low permeability New York oil sands proved difficult. The results of this test were inconclusive.

F. MISCIBLE DISPLACEMENT METHODS

Miscible flood processes utilize a solvent as the displacing fluid to reduce the oil/water interfacial tension. The solvent can be alcohol,

ketones, carbon dioxide, petroleum gas, refined hydrocarbons, liquified natural gas or inert gas (Interstate Oil Compact Commission, 1974). The most common miscible drive techniques use high pressure gas or miscible hydrocarbons.

1. High Pressure Gas Injection

High pressure gas injection involves the use of hydrocarbons or inert gases (Latil, 1980). Carbon dioxide (CO_2) and nitrogen (N_2) are the most widely used inert gases for high pressure miscible drive.

CO_2 is applicable to reservoirs with a wide range of characteristics as shown in Table 12.1.

Even at operating pressures less than that needed for miscibility, CO_2 injection can provide an effective recovery mechanism. Oil viscosity is reduced and displacement is achieved by a process similar to solution gas drive.

The main disadvantage of using CO_2 is its low viscosity, which promotes "fingering" and early gas break-through in the production wells. Slugs of water are normally injected to reduce "fingering". Also, highly corrosive carbonic acid is formed when CO_2 mixes with water. Corrosion protection is necessary and can be cost prohibitive.

Despite discovery of large volumes of natural CO_2 in close proximity to major displacement projects, the recent decreases in the price of crude oil may affect the status of CO_2 flooding. Under specific reservoir conditions, N_2 flooding would be the next best cost effective miscible drive mechanism.

Nitrogen can be used to miscibly displace high gravity reservoir oil provided that the system pressure is usually more than 5,000 psia. The process is best applied to steeply dipping reservoirs containing high gravity oil where a gravity stabilized process can be used.

The drawbacks of miscible nitrogen injection are similar to those of CO_2 flooding. Specifically, nitrogen reacts with formation water which results in the formation of highly corrosive nitric acid. These disadvantages must be evaluated carefully against anticipated increased production.

2. Miscible Hydrocarbon Displacement

Displacement with miscible hydrocarbons is achieved by utilizing hydrocarbon based gases in one of three processes. These are known as the miscible slug, enriched gas, and high pressure lean gas processes (Van Poolen and Associates, 1980).

During the miscible slug process, a solvent is introduced into the formation between the oil contact and its impermeable confining zone. As the injection proceeds the solvent slowly invades the oil bearing formation in a downward fashion mobilizing the oil-in-place. The solvent slug is then followed by a less expensive mobility slug of natural gas or gas and water to displace the oil.

Since solvent is usually more expensive than oil, economics dictate that utilizing a solvent slug process must be accomplished by a "recovery and recycle" method. Reservoirs with a confining impermeable zone and a steep dip can be flooded with reasonable assurance that the solvent can be recovered.

The enriched gas process consists of injecting a slug of natural gas primed with ethane, propane and butane, followed by a slug of lean gas or lean gas and water. This process requires high pressure which can limit the type of reservoirs available for flooding of this nature.

The high pressure lean gas process is similar except only lean gas (methane) is injected and the miscible components are transferred from the oil to the gas which forms a miscible bank. As detailed in Table 12.1, miscible hydrocarbon displacement is applicable to formations containing oil with highly volatile components. Like the enriched process, high reservoir

pressures (3,000 to 4,500 psi) are required. Oil gravities must be greater than 40° API and reservoir depth must be in excess of 5,000 feet for the lean gas process (van Poolen and Associates, 1980).

Miscible hydrocarbon displacement is a proven, feasible process with application to many reservoirs and fluid types. It is limited, however, to high pressure, light oil systems which necessitates its application relatively early in the producing life of most reservoirs. The technique also suffers from high solvent costs and poor oil/solvent mobility ratios (van Poolen and Associates, 1980).

3. New York's Miscible Drive Projects

As with chemical flooding, miscible drive projects have been minimal in New York. During the 1950's, three tests were conducted in Allegany and Cattaraugus Counties. The first test, conducted in 1950-51, consisted of injecting under 1,000 psi pressure, gaseous and liquid CO_2 followed by water into the Richburg sandstone. A similar test was also conducted in Allegany County in a different township. In both cases, slightly higher oil recovery was realized with increases in water injectivity rates. The third test, in Cattaraugus County, was conducted in the Bradford third sand with inconclusive results.

From 1962 to 1965 another miscible drive attempt was made in New York. Injection took place in the Richburg sandstone in Allegany County. The test consisted of injecting slugs of gasoline, CO_2, and water. Approximately 2,789 barrels (117,138 gallons) of gasoline were injected into the formation followed by 855 tons of CO_2. No significant incremental oil was recovered from a well located 225 feet away.

G. THERMAL RECOVERY METHODS

Thermal recovery methods include cyclic steam injection, continuous steam

injection or steam flooding, and in-situ-combustion. Field application of these methods is second only to waterflooding.

Thermal recovery techniques are used to add heat to the reservoir thus lowering the viscosity of the oil by increasing its temperature. The less viscous oil is then more easily displaced to the producing wells. Reservoirs with viscous oil or tars are best suited to thermal processes.

1. Steam Flooding

Steam flooding is somewhat analogous to waterflooding since displacement of the oil is accomplished by condensed steam (Interstate Oil Compact Commission, 1974). Figure 12.5 shows a simplified arrangement of a steam injection system.

The main advantage of steam injection is the wide variety of reservoirs capable of sustaining a steam drive as detailed in Table 12.1 (Van Poollen and Associates, 1980). Two limiting factors are maximum reservoir depth of 3,000 feet and formation thickness of 20 feet or more.

Steam flood operations are generally conducted on one to three acre spacing utilizing a five spot pattern or a line-drive configuration. However, seven and nine spots are also used in cases where the oil is extremely viscous.

The major drawbacks of steam flooding are the large amounts of high quality water required, restriction to depths of less than 3,000 feet, and high fuel consumption per barrel of oil produced.

2. Cyclic Steam Injection

Cyclic steam injection also known as steam stimulation, steam soak or huff and puff, is an established method of enhanced oil recovery (National Petroleum Council, 1984).

The steam stimulation process involves the injection of up to 20,000 barrels of steam in a producing well over a one to three week period. The

FIGURE 12.5   STEAMFLOOD RECOVERY PROCESS
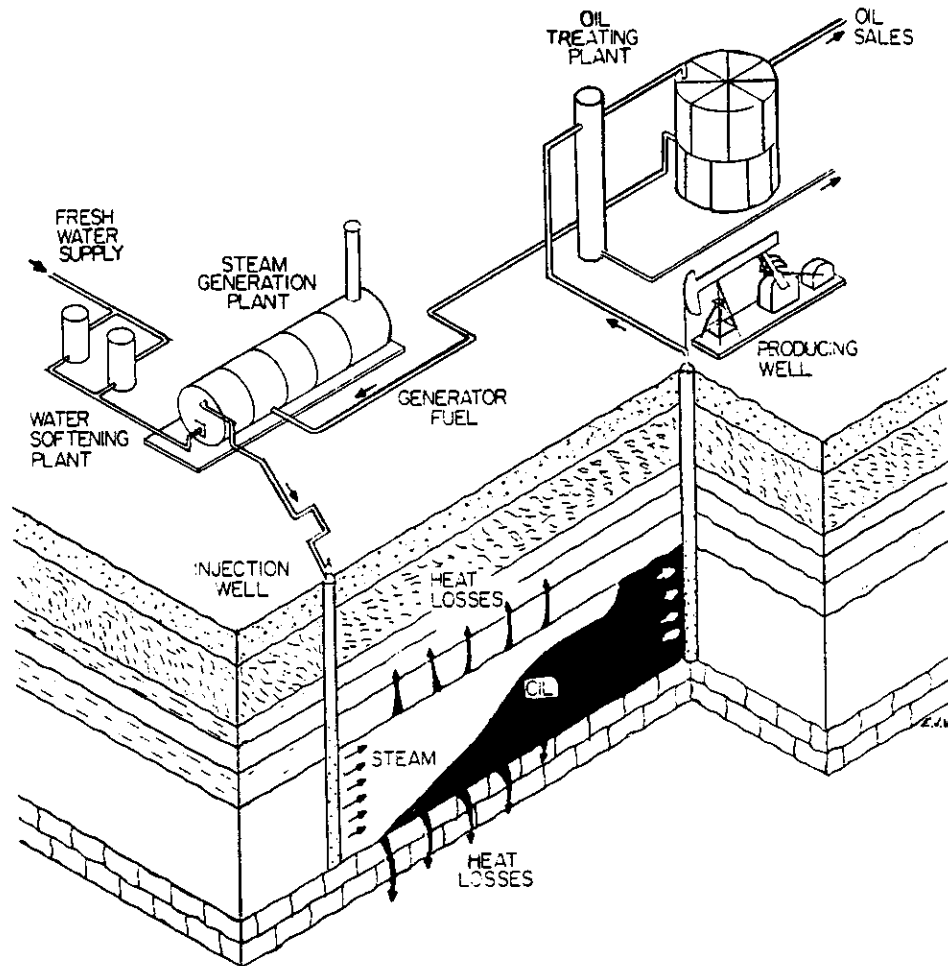
Source: Improved Oil Recovery, Interstate Oil Compact Commission, 1983.

FIGURE 12.5

12-29a

well is then allowed to "soak" for a number of days before being returned to production. The injection, soaking and production of the well is known as a cycle which is usually repeated every 12 to 15 months. As many as 15 cycles can be applied to one well, but production efficiency will generally diminish from cycle to cycle. The steam stimulation process will recover less total oil per well than a steam flood operation, but it is less expensive (van Poollen and associates, 1980). Steam stimulation can be effective in less homogenous reservoirs because a flood front need not be established.

3. In-Situ-Combustion

In-situ-combustion or fire flooding utilizes air injection to supply oxygen to a burning front in the reservoir. When air injection begins, the oil near the injection well oxidizes. If the oil oxidizes rapidly, it will ignite spontaneously and begin to burn. If the oxidation is slow, a heater is placed in the hole and the oil is ignited. Once the oil is ignited, injected air will cause the burning front to move out through the reservoir and away from the injection well. Combustion gases flow ahead of the front and are produced with oil and water (National Petroleum Council, 1984).

The heat produced at the front vaporizes formation water and develops a steam zone ahead of the front (National Petroleum Council, 1984). This steam displaces much of the heavy oil leaving relatively low oil saturations to be burned as the fire front progresses.

The practical guidelines for initiating any in-situ-combustion project are outlined in Table 12.1.

Air is injected at rates sufficient enough to maintain a burning front in the reservoir. Typical fronts advance at .125 to 0.5 feet per day (Interstate Oil Compact Commission, 1983).

Disadvantages of in-situ-combustion include inefficient vertical sweep in

thick formations and loss of heat to adjacent formations.

4. New York's Thermal Drive Projects

From 1957 to 1958, a thermal project was conducted on the Richburg sandstone in Allegany County. The test consisted of an in-situ-combustion pilot utilizing a 2 1/2 acre five spot. Although ignition attempts began in August 1957, ignition was not attained until August 1958. Ignition was sustained for 37 days, but a combustion front was not achieved. The test ended after an explosion occurred upon injection of a fuel mix. No incremental production results were observed.

During the Mid 1960's, two steam flood projects were conducted in Cattaraugus County in the Chipmunk sandstone. After two years of high pressure steam injection, the projects were deemed uneconomic and were abandoned. However, some additional oil was recovered from these projects.

In 1982, a cyclic steam operation was attempted in Allegany County. A thruster was placed on the wellhead and hydrogen peroxide (H_2O_2) and small volumes of ammonia derivatives were injected under high temperature (1,200°F) and pressure (2,200 psi). Theoretically, at bottom hole conditions the H_2O_2 would convert to water (H_2O) and oxygen (O_2) with oxygen providing the catalyst for increased temperature, which would then convert the water to steam.

Despite pre-test optimism, the many problems encountered during the test resulted in its failure. Cement plugs were displaced in offset abandoned wells, a compressor truck's pump overloaded and failed, and the formation was overpressured which may have propagated existing fractures. Production rates were initially high but then declined rapidly.

At the time of the 1982 test, the operator contended that the methodology was stimulation and not enhanced oil recovery. In either case, conditions were imposed on the operator administratively since few specific regulations exist

for stimulation or enhanced oil recovery operations.

Clear consistent regulatory guidelines for such an operation may have
circumvented some of the problems associated with this project. Although the
administrative action achieved its goal, case-by-case procedures must be
replaced by regulations.

H. EXISTING REGULATIONS

Sections 557.1 - 557.4 of the New York State Department of Environmental
Conservation regulations govern secondary recovery and pressure maintenance
operations. Injection and production wells utilized in these operations must
also conform to Parts 550 through 556 of DEC's regulations which govern
organizational reports, bonding, drilling and plugging of oil and gas wells
and operating practices. Amendments to the Oil, Gas and Solution Mining Law
passed in 1981 are being addressed by adding specific safety and environmental
conditions to individual drilling and plugging permits until new regulations
are promulgated.

1. Permit Application for Secondary Recovery Projects

The existing regulations require that the owner or operator of any lease
or unit must file an application and receive a permit from the Department
prior to conducting any secondary recovery or pressure maintenance operations
[6NYCRR Part 557.1 (a)]. When the regulations governing secondary recovery
and pressure maintenance operations took effect in 1966, those projects in
place at that time did not have to file for a permit. They are, however,
subject to other Department regulations. Prior to granting a permit, DEC
staff evaluates potential environmental impacts which may result from the
proposed operation. The application must include, but is not limited to:

a. A neat, legible plat drawn to scale must accompany the application and
   must identify the following:

1. location of the lease, group of leases or unit containing the proposed project;

2. location of the proposed intake well or wells;

3. location of any major surface facilities pertinent to the proposed project;

4. identification of offsetting leases and names of offsetting operators;

5. locations, surface elevations and production zones of all drilling and existing oil and gas wells, abandoned wells and dry holes in the group of leases or unit containing the proposed injection well [6NYCRR Part 557.1(b)(5)].

b. A summary of the proposed operations along with a forecast of the anticipated rate of development of the area within the project [6NYCRR part 557.1(b)(1)].

c. The name, description and depth of the formation for which the operations are proposed [6NYCRR Part 557.1(b)(2)]. Copies of logs of any existing well to be used for input or any available information relative to the geology of the area [6NYCRR Part 557.1(b)(3)].

d. A tabulation showing recent gas-oil ratios and oil and water production tests for each of the producing oil and gas wells [6NYCRR Part 557.1(b)(6)].

e. A statement outlining what secondary recovery or pressure maintenance operations are proposed including the injection medium to be used, its source and the estimated amounts to be injected daily [6NYCRR Part 557.1(b)(1)].

f. A description of the casing program of existing or proposed input wells along with the proposed method for testing the casing seat(s) [6NYCRR Part 557.1(b)(4)].

The Department must review casing programs to determine that sufficient quantities of good quality casing and cement will be utilized in new input wells. Casing programs of existing wells must be reviewed to ascertain that casing integrity is maintained.

Geologic studies of the area using structure and isopach maps and cross sections are very important for a comprehensive evaluation of an injection project. These studies can reveal local faults and fractures which penetrate the targeted formation and the overburden. These geologic features may provide conduits for migration of oil and brine into freshwater aquifers, particularly if reservoir pressures are increased sharply as a result of high injection pressures. Currently DMN has very little geologic information on the old fields being waterflooded.

The current regulations require that only gas-oil ratios, oil and water production tests and descriptions of casing programs be submitted with the application.

2. Offsetting Leases

The permit application must also include a list of names and addresses of the offset operators and a statement that each offsetting operator was sent a copy of the application by registered mail [6NYCRR Part 557.1(b)(7)(c)]. The Department must hold the application for 15 days before issuing a permit unless it involves the unit operation of a pool. Within this 15 day period, if any offset operator files a written protest with just cause or the Department declines to issue the permit, a public hearing must be scheduled to review the application. If there is no objection by an offset operator or the Department within the 15 day period, the application will be approved and a permit issued [6NYCRR Part 557.1(d)]. The 15 day waiting period is not required if the application is accompanied by the written consent of the

operators of all the offsetting leases or units and if the Department has no objection [6NYCRR Part 557.1(e)].

3. Integration and Unitization

If the proposed secondary recovery or pressure maintenance operations will involve the unit operation of a pool or any part of the pool which has been or is proposed to be subject to an integration and unitization ruling by the Department under Title 9 of Article 23 of the Environmental Conservation Law (Section 79 of Article 3-A of the Conservation Law prior to recodification), the application must also contain:

a. A statement or graph showing the rate of anticipated oil and gas production;

b. A statement showing the value of the estimated additional oil and gas production will exceed the estimated cost of the operations;

c. Evidence that 60 percent or more of the interests of the owners and 60 percent or more of royalty interests have approved the proposed operations [6NYCRR part 557.1(f)].

In addition, the Department shall not adhere to the 15 day waiting period but shall promptly schedule a public hearing [6NYCRR Part 557.1(g)].

When a pool is operated as a unit, several owners have economic interests in the operations of the pool. Advantages and disadvantages of secondary recovery operations versus the rights of minority interests must be weighed and reviewed to determine if it is in the best interests of at least 60 percent of the owners.

Any drilling, casing and completion operation must conform to existing regulations in Part 554, Drilling Practices and Reports. Section 553, which establishes spacing requirements, may affect future waterflood operations since oil fields discovered before 1981 are excluded from these provisions. All of New York's current waterflood projects were in operation prior to 1981,

which excludes them from these spacing requirements.

4. Federal Underground Injection Control Regulations

All secondary recovery and enhanced oil recovery injection wells are classified as Class II wells under the Federal Underground Injection Control Program (UIC). The Federal UIC program for New York State is administered by the Environmental Protection Agency (Region II).

All existing Class II wells are authorized by rule for life and must comply with financial responsibility, mechanical integrity, and operational and reporting requirements by June 25, 1985, and every five years thereafter. Operators of new Class II wells must file an application which includes well or field history, an abandonment plan and financial responsibility bonds, and must receive a permit prior to injection. Refer to Chapter 15 for a summary of UIC regulations governing Class II wells.

Many operators of existing Class II wells are currently plugging and abandoning these wells rather than conforming to UIC requirements. Additional costs associated with compliance, as much as an estimated $1,000 per injection well per year for monitoring, have made it uneconomical to continue operation.

I. ENVIRONMENTAL CONSIDERATIONS

New York's old waterflooded fields have produced oil since before the turn of the century. Air, gas and water have been injected since the early 1900's and wells were drilled and abandoned, usually in good-faith, by operators using "state-of-the-art" techniques. However, many past practices as well as the current practices of some operators have contributed to localized contamination of surface and groundwaters, air and soil. Local residents are primarily affected by the contamination and have endured health problems and various inconveniences associated with this pollution.

Contamination problems in the old waterflooded fields can result from:

1. Improperly abandoned or unplugged wells which provide conduits for oil or brine into aquifers or surface waters.

2. Improperly cased and cemented production and injection wells which also provide conduits for oil or brine into aquifers or surface waters:

3. Disrepair of wellheads, pump jacks, or surface flow lines, which allows oil or brine to migrate from the surface and percolate into aquifers;

4. Discharge of excess water and filter backwash into surface waters;

5. Discharge from tanks and separators into surface waters; and

6. Discharge into surface waters and infiltration into groundwaters from unlined pits.

Several cases of surface contamination have been documented in the old waterflooded fields in the past 10 years. Some surface streams and creeks including classified trout streams have permanent oil films caused by run-off from abandoned wells and leaking production equipment. Produced water discharges into surface waters can also contain crude oil constituents which contribute to contamination. Large tree kills and damage to wetlands caused by oil and/or brine spills have also been documented.

Numerous studies have been conducted on the effects of oil spills into surface waters and onto the ground surface. A Pennsylvania study states that an oil spill as small as 1/2 barrel of crude oil into surface waters will reduce the bottom fauna population below the spill by 90 percent (Pennsylvania Department of Environmental Resources, 1985). Downstream effects vary with stream volume and gradient. A two year study of Pennsylvania streams reports that samples of bottom gravel and sediment showed that significant quantities of oil and grease from past surface discharges had permeated deeply into the stream substrate and would affect aquatic life and fauna for many years.

Nature does recover, however. Many of the streams in Pennsylvania which were used as open conveyances for crude oil at the turn of the century are now excellent trout streams (personal communication, Pennzoil, 1986).

Crude oil contamination of groundwater aquifers has been documented in several of the old waterflood field areas. In one instance, it was reported that 8 feet, or 12 gallons, of crude oil was floating on top of the water in a domestic water well. In the proximity of many of the old field areas, groundwater has an oily taste and odor. High levels of benzene, toluene and xylene, soluble constituents of crude oil, have been detected in domestic water wells causing serious health concerns to local residents.

Benzene, toluene and xylene poisoning can occur even from inhalation of the vapor or absorption through the skin. Toluene and xylene are suspected carcinogens and benzene is a known carcinogen. Benzene is one of fourteen pollutants found by the Environmental Protection Agency to be so toxic that the ambient water concentration should be zero for potable water. Department of Environmental Conservation rules and regulations establish effluent limitations for discharges into freshwater aquifers and prohibit the discharge of any detectable level of benzene into potable waters. Samples of one domestic water well taken during a complaint investigation showed levels of benzene as high as 134 mg/1 (milligrams per liter).

Many of the environmental impacts associated with waterflooding and all enhanced oil recovery methods are essentially extensions of those encountered during routine primary recovery operations. There are, however, other impacts specifically associated with deployment of enhanced recovery techniques. These impacts are the result of injection under pressure of liquids or gases to mobilize and displace oil. Table 12.2 details the environmental and safety hazards associated with EOR chemicals and Table 12.3 lists some of the other

TABLE 12.2 COMMON USAGE OF ENHANCED OIL RECOVERY (EOR) CHEMICALS

TABLE 12.2
12-38a

Chemical	Primary Uses (non-EOR)	Production	Maximum Concentration Expected in EOR (ppm)	Maximum Concentration Expected In Handling (%)
Polymers				
Polyacrylamides	Food additives.	50 million lb/yr	5,000	80
Polysaccharides (Xanthan Gums)	Food additives. Cosmetics. Emulsifier.	40 million lb/yr	5,000	80
Surfactants				
Petroleum Sulfonates	Detergents.	600 million lb/1966	100,000	95
Synthetic Sulfonates (Alkylaryl Sulfonates)	Industrial & household. Detergents.	8 million lb/1966	100,000	95
Alkaline Agents				
Sodium Hydroxide	Chemical & metal processing. Paper & pulp manufacture.	9.6 million tons/1975	50,000	50
Sodium Carbonate (Soda Ash)	Industrial processes.	8.7 million tons/1979	20,000	
Sodium Silicate	Chemical manufacture. Adhesives, soaps, fireproofing.		20,000	38

TABLE 12.2 (CON'T)

TABLE 12.2 (CON'T)

12-38b

Chemical	Primary Uses (non-EOR)	Production	Maximum Concentration Expected in EOR (ppm)	Maximum Concentration Expected In Handling (%)
Biocides				
Acrolein	Chemical manufacture (acrylic acid and esters). Biocide.	38,500 tons/1979	150	–
Formaldehyde	Chemical manufacture (resins). Biocide.	3.0 million tons/1975	150	37
Dichlorophenols	Chemical intermediate. Industrial and agriculture products.	–	150	–
Pentachlorophenol	Almost 100% usage as wood preservative. Biocide.	18,200 tons/1975	150	–
Oxygen Scavengers				
Sodium Hydrosulfite	70% dye industry. 18% pulp & paper industry.	50,000 tons/1975	20,000	90
Hydrazine	Solar Flux. Industrial water treatment. Rocket fuel.	–	20,000	98
Others				
Butanols	Industrial solvent (surface coatings). Chemical manufacture.	237,000 tons/1976	40,000	99
Isopropyl Alcohol	Chemical manufacture. Solvent, medical, and cosmetic.	881,000 tons/1972	–	99

Reference: Enhanced Oil Recovery, National Petroleum Council, June 1984.

TABLE 12.3   HAZARDS OF ENHANCED OIL RECOVERY CHEMICALS

TABLE 12.3
12-38c

Chemical	Major Hazard(s)	Other Hazard(s)	OSHA-NIOSH*	IDLH**	Comment
Polymers					
Polyacrylamides	Monomer impurity may be a neurotoxin.	Dust accumulations may be explosive. May cause allergy.	N/A	N/A	Low hazard.
Polysaccharides (Xanthan Gums)	Impurities in commercial xanthans may be irritants or allergens.	Dust accumulations may be explosive May cause allergy.	N/A	N/A	Low hazard.
Surfactants					
Petroleum Sulfonate	Some constituent or impurities may be carcinogens.	Irritating to tissues. Flammable	N/A	N/A	Low to moderate hazard
Synthetic Sulfonate (Alkylaryl Sulfonates)	Impurities potential carcinogen.	Irritating to tissues.	N/A	N/A	Low to moderate hazard.
Alkaline Agents					
Sodium Hydroxide	Severely corrosive to tissue.	--	2 mg/m^3	200 mg/m^3	High hazard. Avoid inhalation, ingestion, & eye/skin contact.
Sodium Carbonate (Soda Ash)	Severely corrosive to tissue.	--	N/A	N/A	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.
Sodium Silicates	Irritant to tissues.	--	N/A	N/A	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.

TABLE 12.3 (CON'T)

TABLE 12.3 (CON'T)

12-38d

Chemical	Major Hazard(s)	Other Hazard(s)	OSHA-NIOSH*	IDLH**	Comment
Biocides					
Acrolein	Inhalation toxicity	Irritant. Fire hazard.	0.1 ppm	5 ppm	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.
Formaldehyde	Irritant to membranes.	Potential carcinogen.	3 ppm (5ppm ceiling) (10 ppm peak)	100 ppm	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.
Dichlorophenols	Aquatic wildlife toxicity.		N/A	N/A	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.
Pentachloropenol	Toxicity to organisms. Potential carcinogen, mutagen teratogen.	Persistent in environment.	0.5 mg/m^3	150 mg/m^3	High hazard. Avoid inhalation, ingestion, & eye/skin contact
Oxygen Scavengers					
Sodium Hydrosulfite	Spontaneous combustion.	Irritant to tissues.	N/A	N/A	Moderate hazard.
Hydrazine	Explosive.	Corrosive to tissue	1 ppm	80 ppm	High hazard. Avoid inhalation, ingestion, & eye/skin contact.

TABLE 12.3 (CON'T)

Chemical	Major Hazard(s)	Other Hazard(s)	OSHA-NIOSH*	IDLH**	Comment
Others					
Butanols	Flammable.	May be irritant to tissues.	100-150 ppm	8,000-10,000 ppm	Low to moderate hazard.
Isopropyl Alcohol	Flammable.	Irritant to respiratory tract.	400 ppm	20,000	Low hazard. Do not take internally.

*OSHA-NIOSH as found in 29 CFR 1910.1000 as of January 1, 1977.

**IDLH--"Immediately Dangerous to Life or Health." Maximum level from which one could escape within 30 minutes without any escape-impairing symptoms or any irreversible health effects. From "Respiratory Protection Reference Document for Chemical Hazards." Standards Completion Program.

N/A -- Not Available.

Reference: Enhanced Oil Recovery, National Petroleum Council, June, 1984.

TABLE 12.3 (CON'T)

12-38e

common uses of EOR chemicals and the concentrations that would be expected in an EOR project. The need for injection wells, lines and facilities causes additional impacts on the environment. Some impacts may be:

1. Expanded land use through more extensive field development including more wells, roads, injection lines, and facilities.

2. Extended duration of land use.

3. Increased emissions of pollutants from additional injection and production facilities.

4. Increased potential for pollution of surface and underground sources of drinking water by injected fluids.

Increased land use results from drilling infill wells, laying new transmission lines, building injection and chemical processing plants, and expanding production facilities. These land use impacts are generally confined to existing field boundaries but their duration may be extended from a few years to several decades by tertiary recovery operations.

Increased air emissions can be generated from steam generators used in thermal processes, from internal combustion engines used to drive gas compressors for miscible processes, from chemical mixing stations for chemical processes, and from additional gas and production processing facilities. Accidental spills and releases of chemicals and gases can result in non-routine air emissions.

Environmental regulations require that the mechanical completion of all injection wells be designed to prevent loss of injected fluids to any part of the wellbore other than the intended injection zone. Failure to adequately complete wells can lead to pollution of subsurface drinking waters by injected nitrogen, natural gas, CO_2 and other chemical solutions.

Specific environmental impacts attributable to each enhanced oil recovery

process must be addressed during the environmental assessment and permitting process.

J. PROPOSED REGULATIONS

The Department believes modification of the regulations dealing with waterflood procedures and operations is required. Not all of these regulations can be directed at current fields and projects but do encompass present activity in New York where applicable. However, as with any revision of regulations, care must be exercised to ensure comprehensive environmental protection under reasonable terms for existing operations. Recommendations for revision of current regulations and reasonings for such revisions are as follows:

1. For new waterflood and tertiary recovery projects and major expansions of existing projects, an additional site specific environmental assessment and SEQR determination are required. Preparation of a site specific supplemental environmental impact statement may be required prior to submittal of an application for any new enhanced oil recovery operation or major expansion of an existing project.

2. Detailed geologic and engineering studies shall be submitted with the application for an enhanced oil recovery project. These reports shall include evaluations of porosity, permeability (effective, relative and absolute), thickness, areal extent of reservoir, fracture gradient, reservoir temperatures, fluid saturations, and fluid properties. Casing inventories of all existing and planned wells, monitoring data, and the results of any injection tests shall also be included.

3. More explicit regulations will be drafted concerning conversion of wells for enhanced recovery purposes. Filing requirements are necessary for the DMN to effectively evaluate the integrity of those wells to be converted.

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4. Spacing criteria will be established by regulation for all new fields which could be influenced by future enhanced oil recovery operations.

5. Fluids from "flowback" operations shall be contained. This requirement will increase environmental protection and the degree of safety involved in many stimulation practices.

6. Injection wells will have to be monitored under the Federal UIC program. This will also satisfy the State's requirements.

7. Injection pressures shall be such as to not propagate fractures. Pressures are limited by the UIC regulations and must also be approved by DMN. The maximum reservoir injection pressure shall be verified by a step-rate pressure test on at lease one injection well in each new project in areas where the maximum injection pressure has not been verified to the satisfaction of the DEC. This requirement parallels the UIC requirements and contributes to groundwater protection.

8. Any unlined earthen ponds or pits designed to hold enhanced oil recovery system byproducts must be eliminated if it is determined that environmental damage is occurring. This includes those pits belonging to peripheral operators under the influence of the flood. For new projects, such fluids shall be stored temporarily in watertight tanks or lined impermeable ponds or pits for subsequent disposal.

9. Plugging and abandonment methods, cement requirements, and disposal methods in the old oil field areas will be required to adhere to those regulations set forth for oil and gas operations.

10. Reporting of produced fluids (oil and water) will be required on the annual production report. Such information assists the DMN in

determining disposal options for produced fluids and ensures that operations are being conducted properly.

11. A chemical analysis of at least one sample of injected and produced water, respectively, will be required on an annual basis for each project. The minimum analysis shall consist of the following parameters: ph, sodium, chloride, specific conductivity, calcium, magnesium, iron, sulfates and total dissolved solids.

Most of these recommendations parallel EPA's UIC program requirements. The reported information required by these proposed regulations combined with existing field inventories and annual reports will greatly improve the ability of the Department to protect the environment, increase safety, protect correlative rights and avoid future potential environmental hazards.

K. FUTURE ENHANCED OIL RECOVERY PROJECTS

Waterflooding will probably continue to be the prevalent oil recovery mechanism in New York's older oil fields in Allegany, Cattaraugus and Steuben counties. Step-out and infill drilling will continue as long as profitable recovery rates are realized. There are several oil producing fields in New York that currently produce without waterflooding. The Busti field, Farmersville Pool, Bass Island Trend and Cattaraugus County's Five Mile Pool, may be viable candidates for future enhanced oil recovery operations. However, since the Busti and Five Mile Pools have low formation permeabilities and the Bass Island trend is so structurally complex, enhanced oil recovery projects in these areas would not be feasible until the reservoir is better understood.

As oil prices increase, some time in the future, projects that once appeared or now appear unattractive may become practical. As mentioned in the discussions relative to chemical, miscible and thermal drive operations, reservoirs must meet specific screening criteria. The oil fields (excluding

the Bass Island fields) in New York have low permeabilities and porosities. There is generally no water encroachment or original gas cap and primary recovery is from solution gas drive. Other general parameters include depths of 800 to 2,000 feet, reservoir temperatures of 70 - 100°F, low dips and structural relief and heterogeneous producing sands of 10 to 35 feet thickness with little or no fractures. Such parameters rule out many chemical drive mechanisms. Miscible recovery methods do appear to have potential for incremental oil recovery in New York's oil fields. Thermal methods may also have some future in New York. However, detailed engineering studies and pilot projects must be undertaken prior to initiating such projects.

Some of the enhanced recovery processes may be adaptable to the Bass Island trend with its complex structure but until more is known about the reservoir, a discussion of applications would be speculative.

Chemical and miscible tests have been conducted on sands in Pennsylvania which are similar to those sands found in New York. Recovery experiments of this nature contribute important information which can be utilized in considering such tests in New York.

L. CONCLUSIONS

The purpose of this chapter is to describe the basics of enhanced oil recovery methods and how they relate to New York's oil and gas program. Enhanced oil recovery techniques are very complex and their application is reservoir specific. Oil recovery predictions based on laboratory experiments and mathematical modeling results are not always achieved in the field.

Chemical, miscible, and thermal methods have at one time or another been attempted in New York. However, waterflooding is the State's most utilized method of enhanced recovery. Waterflooding has brought direct and indirect economic rewards to hundreds of individuals and industries. However, these

rewards have been offset to some degree by environmentally unacceptable impacts brought on by such operations.

Since the waterflood process was discovered by the accidential discharge of groundwater into an inadequately abandoned well, it might be perceived that this method is environmentally unsound. Although present day environmental protection techniques far exceed previous methods, continued improvements in existing waterflood areas are needed to ensure safety and the protection of human health and the environment.

Enforcement in the waterflood and old oil fields will be given top priority by the Department. New and existing regulations, especially those concerning casing integrity, will be thoroughly enforced.

Brine pits will be phased out and permits for surface discharges under SPDES restricted. Improperly plugged and abandoned wells need to be identified and properly plugged since they can act as conduits for migration of oil and brine into freshwater aquifers. The Department will actively pursue a program to eliminate this major environmental problem.

Elimination of unlined storage pits and surface discharges and regular maintenance of pipelines, stock tanks and wellhead equipment would immediately improve situations now causing surface pollution in the old oilfields being waterflooded. Improved production practices and the assurance of the integrity of the cement, casing and injection strings of the wells in combination with adequate disposal plans, controlled road discharges and/or permitted disposal wells, would greatly assist in preventing pollution.

Future enhanced oil recovery projects will have to meet more stringent conditions than those projects started prior to regulations. Certainly a site specific environmental impact statement must be required before the initiation of a new enhanced oil recovery project. An overall awareness of possible hazardous impacts should prevent any environmental damage. Future operations

will be meticulously scrutinized by the public and government agencies alike.

The outlook for enhanced oil operations is contingent on numerous variables. The price of oil, regulatory requirements, environmental considerations and reservoir characteristics are the major parameters that affect enhanced oil recovery projects. A favorable combination of these factors and an educated private and public sector should stimulate both environmental protection and future growth.